MINNKOTA POWER COOPERATIVE, Inc. and
SQUARE BUTTE ELECTRIC COOPERATIVE

RESPONSES TO NDDH REQUEST
NOx BACT ANALYSIS STUDY
MILTON R. YOUNG STATION UNIT 1 and UNIT 2
REGARDING SCR ECONOMIC FEASIBILITY

December 11, 2009

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has requested[1] that Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") provide more detailed and comprehensive cost data following their reviews of the Best Available Control Technology (BACT) Analysis Study – Supplemental reports[2] submitted on November 12, 2009 for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station ("MRYS"). A detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has recently advised[3], are attached. Responses to the use of steam from the main boilers for reheat of the flue gas are provided. A comparison of control costs from relevant recent BACT Determinations versus the estimated control costs of hypothetical applications of low-dust and tail end SCR technologies at MRYS included with the November 2009 Supplemental Reports is also provided.

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced NO_X BACT Analysis Study[4] of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS) in accordance with the requirements of a Consent Decree (CD)[5]. The November 2009 NO_X BACT Analysis Study Supplemental Reports were generated in response to the NDDH's request[6] to see Steps 3 and

[1] See Reference number 1, November 25, 2009.
[2] See Reference number 2, November 12, 2009.
[3] See Reference number 3, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.
[4] See Reference number 4, October 2006.
[5] See Reference number 5, April 24, 2006.
[6] Ibid Reference number 3, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

4 of the BACT analysis process[7] be performed and include low-dust and tail end SCR alternatives.

Detailed NOx BACT Analysis Study Supplemental reports' Capital and Operating & Maintenance Cost Summary:

NDDH Request: "A detailed breakdown of capital costs and operation and maintenance costs for the bulleted items on page 4-16 should be provided."[8]

BMcD Response:

The referenced "bulleted items on page 4-16" of the November 2009 NOx BACT Analysis Study Supplemental reports are intended to represent the major components (physical assets) that were identified as being required to install and operate low-dust and tail end SCRs if they were considered technically feasible for application at MRYS. Preliminary SCR Cost Estimates used as inputs to the November 2009 NO_X BACT Analysis Study Supplemental Reports were not developed based upon a direct match to each of the bulleted items included in the reports. Thus it is not possible to provide a cost breakdown in that format. In lieu of a breakout directly corresponding to the bulleted items, Burns & McDonnell has modified our cost estimate spreadsheets for the four "shared facilities" as well as the four "stand alone" hypothetical applications of SCR technologies analyzed, to reflect the cost tabulation format used in the "SCR Chapter" of the "EPA Air Pollution Control Cost Manual – Sixth Edition" (Section 4.2; Chapter 2).

Please see the attached "Shared Facilities Total Capital Investment" and "Stand Alone Total Capital Investment" cost estimate tables that follow the outline of Table 2.5 in the SCR Chapter of EPA's Control Cost Manual[9] for these hypothetical applications of SCR technologies analyzed. Note that this SCR Chapter of the EPA Control Cost Manual is intended for estimating costs of high dust SCRs, as it states on page 2-41 that "costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher

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[7] See Reference number 8, October 1990.
[8] Ibid Reference number 1, November 25, 2009.
[9] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-44, January 2002.

than the high-dust SCR systems due to flue gas heating requirements"[10]. The SCR Chapter of the Control Cost Manual also states that "the cost methodology is valid for a low-dust SCR system because the cost reductions are expected to be within the range of uncertainty for study-level costs"[11]. We also suggest that the SCR Cost Manual is not suitable for estimating the costs for the cold-side low-dust SCR arrangement analyzed in the Supplemental NOx BACT reports for MRYS because of the flue gas reheating required.

Also see attached tables of estimated "Shared Facilities Total Annual Costs" and "Stand Alone Total Annual Costs" that include the items described in pages 2-44 through 2-49 of the SCR Chapter of EPA's Control Cost Manual[12] for an SCR application. As previously mentioned, the equations in the SCR Cost Manual's cost methodology were not used for estimating annual costs of electrical power consumption, reagent usage, and catalyst replacements. Note that budgetary vendor quotes were the primary source of information used to calculate these estimated annual costs of the hypothetical applications of SCR technologies analyzed.

<u>Use of Steam from the main boilers for reheat of flue gas (for low-dust and tail end SCR alternatives)</u>:

NDDH Request: "The use of steam from the main boilers for the flue gas reheat should also be addressed."

BMcD Response:

Natural gas-fired flue gas reheat is shown in the SCR Chapter of EPA's Control Cost Manual for an SCR application of a tail end SCR example[13], so the use of such reheat systems is not unique to Minnkota's study. MPC selected natural gas firing and rejected the use of steam for flue gas reheating for the evaluation of hypothetical applications of low-dust and tail end SCR technologies at MRYS. For the SCR cost estimate study by Burns & McDonnell, it was necessary to establish the scope conceptual design basis for estimating the costs associated with installation and operation and maintenance of the hypothetical applications of low-dust and tail

[10] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-41, January 2002.
[11] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-41, January 2002.
[12] Ibid Reference number 9, Section 4.2, Chapter 2, pages 2-44 – 2-49, January 2002.
[13] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-21, January 2002.

end SCR technologies. Minnkota's selection of natural gas-fired flue gas reheating for these conceptual designs and cost estimates was made in order to avoid additional loss of unit electrical energy generation output capacity.

A preliminary high level conceptual review of the MRYS Unit 1 steam cycle was done by Minnkota to investigate the feasibility of using steam to achieve the estimated heat duty (31.1 million BTU/hr to raise flue gas temperature from 555°F to 580°F for one reactor) required for the hypothetical application of low dust SCR technology. This preliminary review indicated that using steam for this service appeared to be feasible but would result in a unit electrical output capacity derate of 4-5 MW. This is because the high-temperature/high-pressure main steam extracted from the boiler for flue gas reheat system would not pass through any stages of the high/intermediate/low pressure steam turbines, so less net electrical energy would be produced.

The value of lost electrical generating capacity was not calculated, but the steady-state long term operation impact is believed to be approximately 50% or more of the total auxiliary electricity demand estimated in the November 2009 NO_X BACT Analysis Study Supplemental Reports' Table C.4-3[14] for the hypothetical application of SCR technologies at MRYS.

The preliminary concept assumed that main boiler steam (high pressure, high temperature, around 1000°F, 2500 psig) would be diverted from the steam turbine's inlet piping, and be routed for supply to the flue gas heating system. This would involve the heating steam supplied being condensed using heating coils inserted into the flue gas ductwork. The condensate liquid would then be returned to the boiler feedwater treatment system for reuse. The 4-5 MW Unit 1 derate for a hypothetical application of low-dust SCR technology does not include additional downtime due to tube leaks or other maintenance issues associated with the flue gas reheat steam system. Higher induced draft booster fan discharge pressure requirement for pressure drop is not included. Use of steam for cleaning the in-duct steam coils' exterior surfaces or the gas-to-gas heat exchanger online during operation using soot blowing is also not included in this estimate of the potential unit derate. The time required to modify the main steam piping and other steam turbine and boiler feedwater treatment system components in the steam cycle power generation

[14] Ibid Reference 2, page 4-27.

and balance-of-plant systems and boiler flue gas systems to accommodate such suggested changes would be lengthy. The duration of an outage to implement such modifications, and value of lost electrical generating capacity, would be significant.

A similar preliminary high level conceptual review of the MRYS Unit 2's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (2 reactors, 48.1 MMBTU/hr each to raise flue gas temperature from 535°F to 580°F) required for a hypothetical application of low-dust SCR technology was not performed. Although sizing was not evaluated for MRYS Unit 2, using a scaling factor (ratio of 477 MW divided by 257 MW nameplate capacity ratings) to estimate Unit 2's derate compared with Unit 1's estimated derate could be applied for an approximation. This would yield a potential Unit 2 electrical generating output capacity derate on the order of magnitude of 8 to 10 MW for a hypothetical application of low-dust SCR technology. Similar impacts and issues as described for Unit 1 would be expected for Unit 2.

A similar preliminary high level conceptual review of the MRYS Unit 1's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (1 reactor, 60.3 MMBTU/hr each to raise flue gas temperature from 520°F to 563°F) required for a hypothetical application of tail end SCR technology was not performed. Although sizing was not evaluated for this case, using a scaling factor (ratio of 60.3 divided by 31.1 heat duties) to estimate Unit 1's derate compared with Unit 1's estimated derate for a hypothetical application of low-dust SCR technology could be applied for an approximation. This would yield a potential Unit 1 electrical generating output capacity derate on the order of magnitude of 8 to 10 MW for a hypothetical application of tail end SCR technology. Similar impacts and issues as previously described for Unit 1 would be expected.

A similar preliminary high level conceptual review of the MRYS Unit 2's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (2 reactors, 50.8 MMBTU/hr each to raise flue gas temperature from 520°F to 563°F) required for a hypothetical application of tail end SCR technology was not performed. Although sizing was not evaluated for MRYS Unit 2, using a scaling factor (ratio of 101.6 divided by 31.1 heat duties) to estimate

Unit 2's derate compared with Unit 1's estimated derate could be applied for an approximation. This would yield a potential Unit 2 electrical generating output capacity derate on the order of magnitude of 13 to 16 MW for a hypothetical application of tail end SCR technology. Similar impacts and issues as described for Unit 1 would be expected for Unit 2.

These estimates of lost electrical generation outputs come from boiler main steam usage, larger induced draft fan power requirements, and potential additional downtime associated with the flue gas reheating systems. Because the MRYS units' electrical energy generation output capacity is limited by the steam energy production capacity of each boiler ("boiler limited"), there is not "free capacity margin" available to offset the megawatt losses. Minnkota also cannot increase boiler hourly heat inputs (coal firing rates) in order to compensate for the decrease in output because the increased emissions from higher firing rates are not permitted.

Additional arguments that support the decision to select natural gas firing and reject the use of steam for flue gas reheating involving hypothetical applications of low-dust and tail end SCR technologies at MRYS:

- Minnkota's previous experience with the use of steam for Unit 2's flue gas desulfurization system absorber outlet flue gas reheat (for stack plume buoyancy) was not positive and the technique was abandoned in favor of reheat via scrubber flue gas bypass. The Consent Decree does not allow Minnkota to continue the use of unscrubbed flue gas for reheating the stack gas[15].
- Boiler-turbine steam systems are complex and sensitive to steam inputs, extractions, and outlet conditions. There was insufficient time available during the SCR cost estimate study to perform a comprehensive analysis of potential performance impacts from the modifications related to the use of steam for flue gas reheat.
- High pressure/high temperature steam piping is expensive to procure and install, and requires special design to accommodate thermal growth and significant weight and dynamic loads without overstress. There was insufficient time available during the SCR cost estimate study to perform a comprehensive analysis of potential hanger supports,

[15] Ibid Reference number 5, April 24, 2006.

pipe sizing and routing from the main steam source to the multiple points of use and return of condensate to the boiler plant.

- The deposits removed during cleaning of the in-duct steam coils fouled by particulate, aerosols, and ash products emitted from the boilers and also removed from the gas-gas heat exchanger upstream of the flue gas reheater will be entrained in the flue gas stream entering the SCR reactor. This will require a "large particle ash screen" that creates more pressure drop than the direct-fired duct burner.

<u>Comparison of Average and Incremental Control Costs for MRYS NOx BACT (for low-dust and tail end SCR alternatives) versus recent BACT determinations</u>:

NDDH Request: "It should be documented that the costs of SCR at the M.R. Young Station are significantly beyond the range of recent costs normally associated with BACT for coal-fired power plants (or BACT control costs in general) for the control of nitrogen oxides (NSR Manual Chapter B, Section IV.D.2.C)."

BMcD Response:

A review of available information on "costs normally associated with BACT" for control of NOx emissions from coal-fired power plants indicates that very little documentation is published. Although both the EPA's RACT BACT LAER Clearinghouse (RBLC) [http://cfpub.epa.gov/rblc/htm/bl02.cfm] and the EPA's "National Coal-Fired Utility Projects Spreadsheet" [available via http://www.epa.gov/ttn/catc/products.html#misc] include an assigned database field for entry of "Control Cost Effectiveness" in units of $/ton, neither of these sources contains much information. The assigned field where the data should be entered is blank in the vast majority of cases entered in these databases.

This dearth of data on BACT cost effectiveness was encountered by EPA Region 8 during its preparation of the "Response to Public Comments" for the Draft PSD Permit for Deseret Power Electric Cooperative's proposed 110 MW waste coal fired unit addition to the Bonanza Power Plant[16]. In seeking to defend the cost basis for its rejection of a control technology as BACT, EPA Region 8 was able to identify only 13 cases (total for all pollutants) in which control cost effectiveness data were identified in recent permit actions involving BACT.

Burns & McDonnell reviewed the cases identified by EPA Region 8 in their response for the Deseret BACT case to determine if any data on "the cost associated with BACT" was available for cases involving NOx control for coal-fired boilers. Of the 13 cases for all pollutants identified by EPA Region 8, only one case involved the rejection of the "top" NOx control

[16] See Reference number 10, pages 29-33.

technology as BACT due to what was identified as "excessive cost". This was the case of MDU's proposed Gascoyne project in North Dakota. The inability of EPA Region 8 to identify more cases in which the permit record clearly establishes the level of NOx control costs illustrates the difficulty of this task.

Burns & McDonnell was able to identify only two other cases, both also in North Dakota, in which the permit record shows that the "top" NOx control technology for a coal-fired boiler was rejected as having an excessive "control cost effectiveness". The relevant data for these cases is tabulated below, and compared to similar information as stated in the Supplemental NO_X BACT reports prepared for MRYS Units 1 and 2.

Previous Coal-Fired Boiler NO_X BACT Determinations Based on Cost Effectiveness

State	Utility	Plant Name	Technology Considered Technically Feasible but Rejected as BACT by State Agency	Average Control Cost of Rejected Technology	Average Control Cost of Technology Accepted as BACT	Technology Recommended as BACT
ND	MDU	Gascoyne	SCR	$7545/ton	$2926/ton	SNCR
ND	South Heart Coal LLC	South Heart	SCR	$7640/ton	$1690/ton	SNCR
ND	GRE	Spiritwood	SCR	$7640/ton	$1843/ton	SNCR

As shown in the table above, for coal-fired boilers the "average cost effectiveness of BACT for NOx" as established in previous permit actions ranges from $1690/ton to $2926/ton. By comparison, the estimated cost for NOx control using SCR, which was rejected as BACT due to excessive costs in these previous cases, ranged from 2.6 to 4.5 times the control cost of the technology established as BACT using the "top down" process.

As shown in the table above, for coal-fired boilers the "average cost effectiveness of BACT for NOx" as established in previous permit actions ranges from $1690/ton to $2926/ton. By comparison, the estimated cost for NOx control using SCR, which was rejected as BACT due to excessive costs in these previous cases, ranged from 2.6 to 4.5 times the control cost of the technology established as BACT using the "top down" process.

Control Cost Data from MRYS Units 1 & 2 Supplemental NOx BACT Reports

"Top" Technology Recommended to be Rejected as BACT	Average Control Cost of "Top" Technology	Average Control Cost of Technology Recommended as BACT	Technology Recommended as BACT
MRYS Unit 1 Low-Dust or Tail End SCR with ASOFA	\$3,396/ton to \$5,969/ton	\$1,265/ton	MRYS Unit 1 SNCR with ASOFA
MRYS Unit 2 Low-Dust or Tail End SCR with ASOFA	\$3,859/ton to \$6,597/ton	\$1,240/ton	MRYS Unit 2 SNCR with ASOFA

In the case of MRYS Units 1 and 2, and taking the range of control costs for SCR (TESCR and LDSCR) with ASOFA as presented in the Supplemental NO_X BACT reports (shown above), the ratio between the cost of the technology proposed for rejection on a cost basis to the cost of the technology proposed as BACT for the MRYS units is quite similar to that seen in previous permit actions. For Unit 1, the cost ratio ranges from 2.7 to 4.7. For Unit 2, the cost ratio ranges from 3.1 to 5.3. Thus it appears that the same rationale that was used to reject SCR technology as being "excessively costly on a \$/ton control cost basis" in the case of these other three North Dakota BACT determinations should also apply to the case of MRYS.

REFERENCES

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Cost Estimate*, dated November 25, 2009.

2. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009; and a separate NO_X BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009.

3. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

4. "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc." Final Report, October 2006 submitted by Minnkota to North Dakota Department of Health.

5. Consent Decree filed in the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034, filed April 24, 2006.

6. ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell NO_X BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006),* written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007.

7. *EPA Region 8 Preliminary Analysis of Burns & McDonnell BACT Analysis For Nitrogen Oxide at Milton R. Young Station, Units 1 and 2 January 8, 2007* faxed by North Dakota Department of Health to Minnkota, January 9, 2007.

8. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

9. EPA Air Pollution Control Cost Manual – Sixth Edition (EPA/452/B-02-001), January 2002.

10. *Response to Public Comments on Draft Air Pollution Control Prevention of Significant Deterioration (PSD) Permit to Construct [Permit No. PSD-OU-0002-04.00]*, U.S. EPA Region 8, August 30, 2007.

ATTACHMENTS

1. "Shared Facilities Total Capital Investment" and "Stand Alone Total Capital Investment" cost estimate tables for Low-Dust and Tail End Selective Catalytic Reduction alternatives, as supporting information regarding Unit 1 and Unit 2 at Milton R. Young Station, November, 2009, Reference number 2, NO_X Best Available Control Technology Analysis Study – Supplemental Reports for Minnkota Power Cooperative, Inc., dated December 7, 2009.

2. "Shared Facilities Total Annual Costs" and "Stand Alone Total Annual Costs" tables for Low-Dust and Tail End Selective Catalytic Reduction alternatives, as supporting information regarding Unit 1 and Unit 2 at Milton R. Young Station, November, 2009, Reference number 2, NO_X Best Available Control Technology Analysis Study – Supplemental Reports for Minnkota Power Cooperative, Inc., dated December 7, 2009.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Capital Investment for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Shared Facilities

DIRECT CAPITAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Purchased Capital Equipment					
(a) SCR System Equipment					
Capital Cost of SCR System	$ 29,738,389	$ 52,565,778	$ 38,796,814	$ 70,418,628	Note 1
Capital Cost of Spare Catalyst					Note 2
(b) Auxiliaries/Balance of Plant	$ 23,756,987	$ 40,894,045	$ 33,414,080	$ 52,307,775	Note 3
(c) Instruments and controls					Note 4
(d) Taxes					Note 5
(e) Freight					Note 6
PURCHASED CAPITAL EQUIPMENT COSTS - TOTAL	$ 53,495,376	$ 93,459,823	$ 72,210,894	$122,726,403	Note 7
(2) Construction Costs					
(a) Foundations and supports	$ 15,097,939	$ 28,304,959	$ 20,041,826	$ 39,631,284	Note 8
(b) Urea storage building					Note 9
(c) Electrical	$ 6,901,578	$ 13,809,256	$ 7,690,294	$ 15,296,131	Note 10
(d) Mechanical/Piping	$ 2,411,613	$ 4,718,286	$ 2,513,213	$ 4,995,255	Note 11
(e) Insulation	$ 3,195,016	$ 4,686,967	$ 5,350,536	$ 7,143,550	Note 12
(f) Painting					Note 13
DIRECT CAPITAL CONSTRUCTION COSTS - TOTAL	$ 27,606,146	$ 51,519,468	$ 35,595,868	$ 67,066,221	Note 14
DIRECT CAPITAL COSTS - TOTAL	$ 81,101,522	$144,979,291	$107,806,762	$189,792,624	Note 15
INDIRECT CAPITAL COSTS					
(3) Indirect Installation Costs					
(a) Engineering & Field Support	$ 12,165,228	$ 21,746,894	$ 16,171,014	$ 28,468,894	Note 16
(b) Construction Mgt & Indirects	$ 3,244,061	$ 5,799,172	$ 4,312,270	$ 7,591,705	Note 17
(c) Startup Expenses	$ 1,582,000	$ 2,938,000	$ 1,582,000	$ 2,938,000	Note 18
(d) Scope Contingency	$ 12,486,493	$ 21,567,604	$ 16,536,353	$ 28,151,800	Note 19
(4) Other Indirect Costs					
(a) Pricing Contingency	$ 12,486,493	$ 21,567,604	$ 16,536,353	$ 28,151,800	Note 20
INDIRECT INSTALLATION COSTS - TOTAL	$ 41,964,276	$ 73,619,274	$ 55,137,991	$ 95,302,199	Note 21
(5) Cost Escalation during Project	$ 26,772,124	$ 40,212,687	$ 35,491,483	$ 52,726,778	Note 22
(6) Interest During Construction	$ 17,441,200	$ 30,047,900	$ 23,097,900	$ 39,221,000	Note 23
(7) Natural Gas Pipeline - Installed	$ 2,362,500	$ 4,387,500	$ 2,362,500	$ 4,387,500	Note 24
(8) Owner's Costs - Other	$ 13,632,335	$ 24,182,077	$ 16,920,540	$ 29,632,862	Note 25
TOTAL CAPITAL INVESTMENT	**$183,273,957**	**$317,428,728**	**$240,817,176**	**$411,062,963**	Note 26

Shared Facilities (SF) represents estimated costs if SCR equipment is retrofitted to both boilers concurrently.
This table follows outline of Table 2.5 of EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44.

Note 1: Includes costs for SCR equipment including initial catalyst, flue gas heat recovery equipment, and flue gas reheat burner equipment as well mechanical setting of this equipment.

Note 2: Does not include spare catalyst in purchased SCR equipment costs.

Note 3: Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion, flue gas reheat gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment.

Note 4: Instrumentation and controls are included in Electrical Construction costs (see Note 10).

Note 5: Sales taxes for engineered equipment and permanent materials is not included; Taxes are included for consumable materials.

Note 6: Delivery expenses are included in equipment costs.

Note 7: Sum of SCR, Auxiliaries/Balance of Plant, and Instruments/Controls equipment costs; taxes and freight.

Note 8: Includes site excavation, structural steel, concrete, and architectural construction costs. Includes SCR bypass ducts and isolation dampers, and interconnecting ductwork construction costs.

Note 9: Estimated separately as shown in Table 4.5 SF in Supplemental BACT Control and Cost Effectiveness Analysis.

Note 10: Instrumentation and Controls, additional plant electrical distribution equipment are included in Electrical construction costs.

Note 11: Mechanical/Piping includes material and installation of all piping not provided with engineered equipment.

Note 12: Insulation includes ductwork and piping insulation.

Note 13: Painting included in structural and architectural construction costs.

Note 14: Sum of Direct Capital Construction Costs.

Note 15: Sum of Total Purchased Capital Equipment and Total Direct Capital Construction Costs; considered to be equivalent to "A" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 16: Sum of Engineering and Field Support Costs.

Note 17: Sum of Construction Management and Construction Indirects.

Note 18: Startup Costs include costs for startup engineering support.

Note 19: Scope contingency is to account for potential changes in the project scope resulting from engineering, equipment, and/or construction work which were not identified or included.

Note 20: Pricing contingency is to account for potential changes in project costs resulting from wages, productivities, equipment and/or materials costs being higher than anticipated. Note: this does not intend to cover pricing increases over time, i.e. Escalation. Considered to be equivalent to "C" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 21: Sum of Indirect Capital Installation Costs; considered to be equivalent to "D", Total Plant Costs in EPA OAQPS SCR Cost Manual Table 2.5.

Note 22: Escalation is a result of anticipated increases in costs that are due to higher costs over time.

Note 23: Interest During Construction (or Allowance for Funds During Construction) are considered to be equivalent to "E" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 24: Natural gas pipeline construction cost was assumed as an owner cost.

Note 25: Other Owner Costs include Owner personnel, insurance, pilot testing, Owner Contingency and Spare Parts.

Note 26: Total Capital Investment (TCI) is equivalent to Installed Capital Cost for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Table 4-5SF, page 4-18. The installed capital cost of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, are not included in these numbers. See Table 4-5SF.

Milton R. Young Station Unit 1 and Unit 2 Estimates of Total Capital Investment for Low Dust and Tail End Selective Catalytic Reduction Alternatives Best Available Control Technology - Supplemental Analysis Stand Alone					
DIRECT CAPITAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Purchased Capital Equipment					
(a) SCR System Equipment					
Capital Cost of SCR System	$ 29,738,389	$ 52,565,778	$ 38,796,814	$ 70,418,628	Note 1
Capital Cost of Spare Catalyst					Note 2
(b) Auxiliaries/Balance of Plant	$ 34,665,617	$ 46,348,360	$ 44,322,710	$ 57,762,090	Note 3
(c) Instruments and controls					Note 4
(d) Taxes					Note 5
(e) Freight					Note 6
PURCHASED CAPITAL EQUIPMENT COSTS - TOTAL	$ 64,404,006	$ 98,914,138	$ 83,119,524	$128,180,718	Note 7
(2) Construction Costs					
(a) Foundations and supports	$ 20,120,339	$ 30,816,159	$ 25,024,641	$ 42,122,692	Note 8
(b) Urea storage building					Note 9
(c) Electrical	$ 8,399,220	$ 14,558,077	$ 9,489,326	$ 19,195,648	Note 10
(d) Mechanical/Piping	$ 4,299,227	$ 5,662,093	$ 4,400,827	$ 5,939,062	Note 11
(e) Insulation	$ 3,288,333	$ 4,733,626	$ 5,443,853	$ 7,190,209	Note 12
(f) Painting					Note 13
DIRECT CAPITAL CONSTRUCTION COSTS - TOTAL	$ 36,107,120	$ 55,769,955	$ 44,358,647	$ 71,447,611	Note 14
DIRECT CAPITAL COSTS - TOTAL	$100,511,125	$154,684,093	$127,478,171	$199,628,329	Note 15
INDIRECT CAPITAL COSTS					
(3) Indirect Installation Costs					
(a) Engineering & Field Support	$ 15,076,669	$ 23,202,614	$ 19,121,726	$ 29,944,249	Note 16
(b) Construction Mgt & Indirects	$ 4,020,445	$ 6,187,364	$ 5,099,127	$ 7,985,133	Note 17
(c) Startup Expenses	$ 1,582,000	$ 2,938,000	$ 1,582,000	$ 2,938,000	Note 18
(d) Scope Contingency	$ 15,436,040	$ 22,988,134	$ 19,529,462	$ 29,593,180	Note 19
(4) Other Indirect Costs					
(a) Pricing Contingency	$ 12,486,493	$ 21,567,604	$ 16,536,353	$ 28,151,800	Note 20
INDIRECT INSTALLATION COSTS - TOTAL	$ 51,551,194	$ 78,304,245	$ 64,861,776	$100,053,742	Note 21
(5) Cost Escalation during Project	$ 30,170,164	$ 42,869,269	$ 42,013,593	$ 55,436,089	Note 22
(6) Interest During Construction	$ 21,561,300	$ 32,027,100	$ 27,278,800	$ 41,228,900	Note 23
(7) Natural Gas Pipeline - Installed	$ 6,750,000	$ 6,750,000	$ 6,750,000	$ 6,750,000	Note 24
(8) Owner's Costs - Other	$ 23,114,224	$ 27,867,439	$ 26,204,034	$ 33,248,637	Note 25
TOTAL CAPITAL INVESTMENT	**$236,658,008**	**$342,502,146**	**$294,586,374**	**$436,345,697**	Note 26

Stand Alone (SA) represents estimated costs if SCR equipment is retrofitted to both boilers independently. This table follows outline of Table 2.5 of EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44.

Note 1: Includes costs for SCR equipment including initial catalyst, flue gas heat recovery equipment, and flue gas reheat burner equipment as well mechanical setting of this equipment.

Note 2: Does not include spare catalyst in purchased SCR equipment costs.

Note 3: Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion, flue gas reheat gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment.

Note 4: Instrumentation and controls are included in Electrical Construction costs (see Note 10).

Note 5: Sales taxes for engineered equipment and permanent materials is not included; Taxes are included for consumable materials.

Note 6: Delivery expenses are included in equipment costs.

Note 7: Sum of SCR, Auxiliaries/Balance of Plant, and Instruments/Controls equipment costs; taxes and freight.

Note 8: Includes site excavation, structural steel, concrete, and architectural construction costs. Includes SCR bypass ducts and isolation dampers, and interconnecting ductwork construction costs.

Note 9: Estimated separately as shown in Table 4.5 SA in Supplemental BACT Control and Cost Effectiveness Analysis.

Note 10: Instrumentation and Controls, additional plant electrical distribution equipment are included in Electrical construction costs.

Note 11: Mechanical/Piping includes material and installation of all piping not provided with engineered equipment.

Note 12: Insulation includes ductwork and piping insulation.

Note 13: Painting included in structural and architectural construction costs.

Note 14: Sum of Direct Capital Construction Costs.

Note 15: Sum of Total Purchased Capital Equipment and Total Direct Capital Construction Costs; considered to be equivalent to "A" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 16: Sum of Engineering and Field Support Costs.

Note 17: Sum of Construction Management and Construction Indirects.

Note 18: Startup Costs include costs for startup engineering support.

Note 19: Scope contingency is to account for potential changes in the project scope resulting from engineering, equipment, and/or construction work which were not identified or included.

Note 20: Pricing contingency is to account for potential changes in project costs resulting from wages, productivities, equipment and/or materials costs being higher than anticipated. Note: this does not intend to cover pricing increases over time, i.e. Escalation. Considered to be equivalent to "C" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 21: Sum of Indirect Capital Installation Costs; considered to be equivalent to "D", Total Plant Costs in EPA OAQPS SCR Cost Manual Table 2.5.

Note 22: Escalation is a result of anticipated increases in costs that are due to higher costs over time.

Note 23: Interest During Construction (or Allowance for Funds During Construction) are considered to be equivalent to "E" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 24: Natural gas pipeline construction cost was assumed as an owner cost.

Note 25: Other Owner Costs include Owner personnel, insurance, pilot testing, Owner Contingency and Spare Parts.

Note 26: Total Capital Investment (TCI) is equivalent to Installed Capital Cost for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Table 4-5SA, page 4-17. The installed capital cost of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, are not included in these numbers. See Table 4-5SA.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Annual Costs for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Shared Facilities

DIRECT ANNUAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Annual Maintenance Costs	$ 4,189,181	$ 7,514,611	$ 5,444,530	$ 9,608,381	Note 1
(2) Annual Reagent Costs					Note 2
Scenario A	$ 2,710,313	$ 4,171,528	$ 2,709,417	$ 4,170,150	
Scenario B	$ 2,725,539	$ 4,204,613	$ 2,724,643	$ 4,204,613	
(3) Annual Electricity Costs					Note 3
Scenario A	$ 5,929,642	$ 9,730,376	$ 6,011,088	$ 9,740,159	
Scenario B	$ 11,939,901	$ 24,539,279	$ 11,982,549	$ 25,083,883	
(4) Annual Water Costs					Note 4
(5) Catalyst Replacement Costs					Note 5
Scenario A	$ 709,951	$ 958,131	$ 709,951	$ 963,350	Note 6
Scenario B	$ 4,387,500	$ 10,260,000	$ 4,387,500	$ 10,260,000	Note 7
(6) Natural Gas for F.G. Reheating & Urea-to-Ammonia Conversion sys.					Note 8
Scenario A	$ 2,136,238	$ 6,064,108	$ 3,931,511	$ 6,416,128	
Scenario B	$ 1,944,698	$ 5,296,499	$ 3,580,852	$ 5,574,558	Note 9
(7) Operating labor for SCR equipment and urea-to-ammonia eqpmnt					Note 10
DIRECT Annual COSTS - TOTAL					Note 11
Scenario A	$ 15,675,326	$ 28,438,754	$ 18,806,498	$ 30,898,167	
Scenario B	$ 25,186,819	$ 51,815,002	$ 28,120,074	$ 54,731,434	
INDIRECT Annual COSTS					
(8) Annual Costs from Capital Recovery	$ 12,174,396	$ 21,838,601	$ 15,822,632	$ 27,923,414	Note 12
(9) Administrative overhead, insurance and property taxes for SCRs and aux.					Note 13
INDIRECT Annual COSTS - TOTAL	$ 12,174,396	$ 21,838,601	$ 15,822,632	$ 27,923,414	
TOTAL ANNUAL COSTS					Note 14
Scenario A	$ 27,849,722	$ 50,277,355	$ 34,629,130	$ 58,821,580	
Scenario B	$ 37,361,215	$ 73,653,603	$ 43,942,706	$ 82,654,848	
LEVELIZED TOTAL ANNUALIZED COSTS					Note 15
Scenario A	$ 31,748,616	$ 57,350,872	$ 39,306,834	$ 66,506,822	
Scenario B	$ 43,625,884	$ 86,541,448	$ 50,936,958	$ 96,268,092	

Shared Facilities (SF) represents estimated costs if SCR equipment is retrofitted to both boilers concurrently.
This table includes values that are identified in the EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44 through 2-49 but use calculated and vendor-quoted values instead of the formulas provided in the OAQPS manual
Total Annual Costs consist of direct costs, indirect costs, and recovery credits (if any). Direct Annual Costs and variable and semi-variable costs that are proportional to the quantity of flue gas processed by the control system. Indirect Annual Costs are fixed costs incurred independent of control operation, and include capital recovery costs, insurance, administrative charges, and overhead (payroll and plant).
Note 1: Annual maintenance was assumed to be 3% of installed capital cost of the SCR equipment and auxiliary equipment related to the SCR systems, not including catalyst replacement costs. Maint. costs for ASOFA are included.
Note 2: Annual reagent costs are for "Scenario A" and "Scenario B" operation and related chemical usage based on receiving 50% aqueous urea solution, assumed to be $379.29 per ton in 2006$.
Note 3: Annual electricity costs are for "Scenario A" and "Scenario B" operation and related electricity consumption and lost generation, assumed to be $35/MW-hr in 2006$. See Tables C.4-1 through C.4-4 in the November 2009 NOx BACT Analysis Study Supplemental Reports for details.
Note 4: Annual water costs were not calculated, but may be more than zero, if concentrated liquid urea liquor (70% concentration) is purchased, which must be diluted to 50% concentration for storage.
Note 5: Annual catalyst replacement costs are for "Scenario A" and "Scenario B" operation, and are assumed to be based on $7,500 per cubic meter in 2006$.
Note 6: Annual catalyst replacement costs for "Scenario A" are assumed to be based one layer per reactor every two years (approx. 16,000 operating hours), and follows the EPA OAQPS SCR Cost Manual for annualizing the purchase cost using Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 assuming 6% per year annual interest rate. Tail end SCRs were assumed to have 10 layers replaced during the 20-year economic evaluation period, and 12 layers for Low-dust SCRs, but the annual catalyst replacement costs for U2 used in the November 2009 NOx BACT Analysis Study Supplemental Report underestimate the cost per layer due to assuming regular depth layers instead of deep layers recommended by vendor.
Note 7: Annual catalyst replacement costs for "Scenario B" are assumed to be based three layers per reactor every year (approx. 2,667 operating hours) for U1 and four layers per reactor per year (approx. 2,000 operating hours) for U2. There were no adjustments for annualizing the purchase cost (Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 of the EPA OAQPS SCR Cost Manual were not used). U1 Low-dust and Tail end SCRs were assumed to have 60 layers replaced during the 20-year economic evaluation period, and 80 layers for U2's Tail end SCRs.
Note 8: Annual costs of natural gas firing for flue gas reheating and urea-to-ammonia conversion system operation for "Scenario A" and "Scenario B" are assumed to be based on $7.98 per million BTU in 2006$.
Note 9: Annual costs of natural gas firing for "Scenario B" are lower than "Scenario A" due to fewer annual hours of operation resulting from additional catalyst replacements.
Note 10: Annual costs of operating labor for SCR equipment, flue gas reheating, and urea-to-ammonia systems were assumed to be zero, but this may underestimate actual requirements.
Note 11: Total Direct Annual Costs are the sum of maintenance, reagent, electricity, catalyst replacements, and natural gas for Scenario A and Scenario B operations. This may underestimate actual requirements.
Note 12: Annual Costs from capital recovery are the same for Scenario A and Scenario B operations. See Appendix C in the 2006 NOx BACT Analysis Study reports for details. The capital recovery factor used to calculate the annual costs is 0.087185. Capital recovery costs for ASOFA are included.
Note 13: Annual costs of increases in administrative overhead, insurance premiums, and property taxes for SCR equipment and related auxiliaries were assumed to be zero, but this may underestimate actual requirements.
Note 14: Total Annual Costs are the sum of increases in Direct Costs and Indirect Costs for SCR equipment and related auxiliaries. These values may underestimate actual requirements.
Note 15: Levelized Total Annualized Costs are TDC multiplied by the levelization factor (1.24873) plus the Total Indirect Annual Costs (capital recovery). See Appendix C in the 2006 NOx BACT Analysis Study Reports for details. These values may underestimate actual requirements.

These numbers are the same Levelized Total Annualized Costs for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Tables 4-6SF, 4-7SF, 4-8SF, and 4-9SF. The capital recovery costs of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, based on the installed capital costs shown in Tables 4-4SF and 4-5SF, are included in these numbers.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Annual Costs for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Stand Alone

DIRECT ANNUAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Annual Maintenance Costs	$ 5,422,167	$ 8,123,552	$ 6,685,918	$ 10,222,003	Note 1
(2) Annual Reagent Costs					Note 2
Scenario A	$ 2,710,313	$ 4,171,528	$ 2,709,417	$ 4,170,150	
Scenario B	$ 2,725,539	$ 4,204,613	$ 2,724,643	$ 4,204,613	
(3) Annual Electricity Costs					Note 3
Scenario A	$ 5,929,642	$ 9,730,376	$ 6,011,088	$ 9,740,159	
Scenario B	$ 11,939,901	$ 24,539,279	$ 11,982,549	$ 25,083,883	
(4) Annual Water Costs					Note 4
(5) Catalyst Replacement Costs					Note 5
Scenario A	$ 709,951	$ 958,131	$ 709,951	$ 963,350	Note 6
Scenario B	$ 5,850,000	$ 10,260,000	$ 4,387,500	$ 10,260,000	Note 7
(6) Natural Gas for F.G. Reheating & Urea-to-Ammonia Conversion sys.					Note 8
Scenario A	$ 2,136,238	$ 6,064,108	$ 3,931,511	$ 6,416,128	
Scenario B	$ 1,944,698	$ 5,296,499	$ 3,580,852	$ 5,574,558	Note 9
(7) Operating labor for SCR equipment and urea-to-ammonia eqpmnt					Note 10
DIRECT Annual COSTS - TOTAL					Note 11
Scenario A	$ 16,908,311	$ 29,047,696	$ 20,047,886	$ 31,511,788	
Scenario B	$ 27,882,304	$ 52,423,943	$ 29,361,462	$ 55,345,056	
INDIRECT Annual COSTS					
(8) Annual Costs from Capital Recovery	$ 15,757,639	$ 23,608,277	$ 19,430,293	$ 29,706,692	Note 12
(9) Administrative overhead, insurance and property taxes for SCRs and aux.					Note 13
INDIRECT Annual COSTS - TOTAL	$ 15,757,639	$ 23,608,277	$ 19,430,239	$ 29,706,692	
TOTAL ANNUAL COSTS					Note 14
Scenario A	$ 32,665,951	$ 52,655,972	$ 39,478,179	$ 61,218,481	
Scenario B	$ 43,639,944	$ 76,032,220	$ 48,791,755	$ 85,051,748	
LEVELIZED TOTAL ANNUALIZED COSTS					Note 15
Scenario A	$ 36,871,522	$ 59,880,950	$ 44,464,651	$ 69,056,347	
Scenario B	$ 50,575,055	$ 89,071,526	$ 56,094,775	$ 98,817,617	

Stand Alone (SA) represents estimated costs if SCR equipment is retrofitted to both boilers independently.
This table includes values that are identified in the EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44 through 2-49 but use calculated and vendor-quoted values instead of the formulas provided in the OAQPS manual
Total Annual Costs consist of direct costs, indirect costs, and recovery credits (if any). Direct Annual Costs and variable and semi-variable costs that are proportional to the quantity of flue gas processed by the control system. Indirect Annual Costs are fixed costs incurred independent of control operation, and include capital recovery costs, insurance, administrative charges, and overhead (payroll and plant).
Note 1: Annual maintenance was assumed to be 3% of installed capital cost of the SCR equipment and auxiliary equipment related to the SCR systems, not including catalyst replacement costs. Maint. costs for ASOFA are included.
Note 2: Annual reagent costs are for "Scenario A" and "Scenario B" operation and related chemical usage based on receiving 50% aqueous urea solution, assumed to be $379.29 per ton in 2006$.
Note 3: Annual electricity costs are for "Scenario A" and "Scenario B" operation and related electricity consumption and lost generation, assumed to be $35/MW-hr in 2006$. See Tables C.4-1 through C.4-4 in the November 2009 NOx BACT Analysis Study Supplemental Reports for details.
Note 4: Annual water costs were not calculated, but may be more than zero, if concentrated liquid urea liquor (70% concentration) is purchased, which must be diluted to 50% concentration for storage.
Note 5: Annual catalyst replacement costs are for "Scenario A" and "Scenario B" operation, and are assumed to be based on $7,500 per cubic meter in 2006$.
Note 6: Annual catalyst replacement costs for "Scenario A" are assumed to be based one layer per reactor every two years (approx. 16,000 operating hours), and follows the EPA OAQPS SCR Cost Manual for annualizing the purchase cost using Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 assuming 6% per year annual interest rate. Tail end SCRs were assumed to have 10 layers replaced during the 20-year economic evaluation period, and 12 layers for Low-dust SCRs, but the annual catalyst replacement costs for U2 used in the November 2009 NOx BACT Analysis Study Supplemental Report underestimate the cost per layer due to assuming regular depth layers instead of deep layers recommended by vendor.
Note 7: Annual catalyst replacement costs for "Scenario B" are assumed to be based three layers per reactor every year (approx. 2,667 operating hours) for U1 and four layers per reactor per year (approx. 2,000 operating hours) for U2. There were no adjustments for annualizing the purchase cost (Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 of the EPA OAQPS SCR Cost Manual were not used). U1 Low-dust and Tail end SCRs were assumed to have 60 layers replaced during the 20-year economic evaluation period, and 80 layers for U2's Tail end SCRs.
Note 8: Annual costs of natural gas firing for flue gas reheating and urea-to-ammonia conversion system operation for "Scenario A" and "Scenario B" are assumed to be based on $7.98 per million BTU in 2006$.
Note 9: Annual costs of natural gas firing for "Scenario B" are lower than "Scenario A" due to fewer annual hours of operation resulting from additional catalyst replacements.
Note 10: Annual costs of operating labor for SCR equipment, flue gas reheating, and urea-to-ammonia systems were assumed to be zero, but this may underestimate actual requirements.
Note 11: Total Direct Annual Costs are the sum of maintenance, reagent, electricity, catalyst replacements, and natural gas for Scenario A and Scenario B operations. This may underestimate actual requirements.
Note 12: Annual Costs from capital recovery are the same for Scenario A and Scenario B operations. See Appendix C in the 2006 NOx BACT Analysis Study reports for details. The capital recovery factor used to calculate the annual costs is 0.087185. Capital recovery costs for ASOFA are included.
Note 13: Annual costs of increases in administrative overhead, insurance premiums, and property taxes for SCR equipment and related auxiliaries were assumed to be zero, but this may underestimate actual requirements.
Note 14: Total Annual Costs are the sum of increases in Direct Costs and Indirect Costs for SCR equipment and related auxiliaries. These values may underestimate actual requirements.
Note 15: Levelized Total Annualized Costs are TDC multiplied by the levelization factor (1.24873) plus the Total Indirect Annual Costs (capital recovery). See Appendix C in the 2006 NOx BACT Analysis Study Reports for details. These values may underestimate actual requirements.

These numbers are the same Levelized Total Annualized Costs for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Tables 4-6SA, 4-7SA, 4-8SA, and 4-9SA. The capital recovery costs of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, based on the installed capital costs shown in Tables 4-4SA and 4-5SA, are included in these numbers.